VERMILION ENERGY

News Release

Vermilion Energy Inc. Announces Results for the Three and Nine Months Ended September 30, 2024

CALGARY, Alberta, November 6, 2024 - Vermilion Energy Inc. ("Vermilion", "We", "Our", "Us" or the "Company") (TSX, NYSE: VET) is pleased to report operating and condensed financial results for the three and nine months ended September 30, 2024.

The unaudited interim financial statements and management discussion and analysis for the three and nine months ended September 30, 2024 will be available on the System for Electronic Document Analysis and Retrieval Plus ("SEDAR+") at www.sedarplus.ca, on EDGAR at www.sec.gov/edgar.shtml, and on Vermilion's website at www.vermilionenergy.com.

Highlights

- Q3 2024 fund flows from operations ("FFO")(1) was $275 million ($1.76/basic share)(2), representing a 16% increase over the prior quarter, primarily due to stronger European gas prices. Benchmark TTF Day Ahead pricing increased 14% over the prior quarter, averaging $15.52/mmbtu in Q3 2024, and European gas was the only commodity in our portfolio that increased quarter-over-quarter and year-over-year. As a result of strong European gas prices, our corporate average realized natural gas price in Q3 2024 was $6.57/mcf, compared to $0.69/mcf for the AECO 5A benchmark.
- Net earnings for Q3 2024 was $52 million ($0.33/basic share), an increase of $134 million over the prior quarter primarily due to a more normalized mark-to-market adjustment on our hedge book.
- We invested $121 million in exploration and development ("E&D") capital expenditures(3), resulting in free cash flow ("FCF")(4) of $154 million ($0.98/basic share)(5), of which $59 million was returned to shareholders, including $19 million in dividends and $40 million of share buybacks, representing 45% of excess FCF ("EFCF")(4).
- Year-to-date, we have returned $180 million ($1.13/basic share) to shareholders through dividends and share buybacks, representing 38% of EFCF, including the repurchase and cancellation of 8.0 million shares which has reduced our outstanding common shares to 155.3 million as at September 30, 2024. We continue to repurchase shares in Q4 2024 and are on track to return 10% of our market capitalization to shareholders in 2024 between our fixed dividend and variable share repurchase program, and expect to continue providing ratable dividend increases and repurchasing shares in future periods.
- Net debt(6) decreased by $73 million in Q3 2024 to $833 million, representing a net debt to trailing FFO ratio(7) of 0.6 times, the lowest in 15 years.
- Production during Q3 2024 averaged 84,173 boe/d(8) (56% natural gas and 44% crude oil and liquids), comprised of 53,936 boe/d(8) from our North American assets and 30,237 boe/d(8) from our International assets, and includes the impact from a planned turnaround in Australia and the partial shut-in of some Canadian gas production due to weak AECO pricing. Our Q3 2024 production represents an increase of 2% year-over-year, or 7% on a per share basis, reflecting the positive impact from our share repurchase program. Notably, production from our International assets has increased 16% over the prior year, including a 26% increase in natural gas production driven by new production from our SA-10 block in Croatia and higher runtime in Ireland.
- In Germany, we successfully completed testing operations for our first deep gas exploration well drilled earlier this year. The well flow tested at a restricted rate of 17 mmcf/d(15) of natural gas with a wellhead pressure of 4,625 psi, which supports our expectation that deliverability would have been higher without testing equipment limitations. Tie-in operations are progressing to bring the well on production in the first half of 2025.
- We commenced drilling on our second deep gas exploration well (0.3 net) in August 2024 and successfully completed drilling operations at the end of October 2024. We are pleased to report that we discovered gas within the reservoir and are now proceeding with completion and testing operations. Subsequent to the quarter, we commenced drilling on our third German deep gas exploration well (1.0 net) in October 2024. We anticipate results from the second well test and third well drilling operations in the first half of 2025.
- In Croatia, we successfully increased production on the SA-10 block after commissioning the gas plant in late June 2024. Production in Q3 2024 averaged 1,855 boe/d (100% European natural gas) and currently exceeds 2,000 boe/d. On the SA-7 block, we completed testing on the third well of our four-well program, at a reservoir depth of 885 metres, which flow tested at 5.6 mmcf/d(16) of natural gas.
- During Q3 2024 we achieved a major safety milestone in Ireland, where we celebrated two years and one million man-hours without a lost time incident, a testament to Vermilion's high standard for safety in our operations.

- In Canada, we completed and brought on production five (5.0 net) Montney liquids-rich shale gas wells during the third quarter. These wells have produced at an average IP90 rate of over 1,000 boe/d[17] per well (43% liquids)[17], which is in line with expectations. The total drill, complete, equip and tie-in ("DCET") cost for the 9-21 pad was approximately $9.6 million per well as we continue to make progress towards our normalized targeted cost range of $9.0 to $9.5 million per well. The new battery and water infrastructure have achieved 99% run time since starting up and are contributing to these cost savings.

- In conjunction with our Q3 2024 release, we announced a quarterly cash dividend of $0.12 per common share, payable on January 15, 2025 to shareholders of record on December 31, 2024.

- We have tightened our 2024 production guidance range to 84,000 to 85,000 boe/d to reflect increased certainty on annual production levels, and our capital budget of $600 to $625 million remains unchanged. We are in the process of finalizing our 2025 budget which will target modest production growth on a similar capital spending level as 2024, while maintaining our return of capital payout target at 50% of EFCF.

($M except as indicated)	Q3 2024	Q2 2024	Q3 2023	YTD 2024	YTD 2023
Financial					
Petroleum and natural gas sales	**490,095**	478,925	475,532	**1,477,055**	1,499,586
Cash flows from operating activities	**134,547**	266,322	118,436	**755,164**	680,697
Fund flows from operations [1]	**275,024**	236,703	270,218	**943,085**	770,494
Fund flows from operations ($/basic share) [2]	**1.76**	1.48	1.65	**5.93**	4.70
Fund flows from operations ($/diluted share) [2]	**1.75**	1.47	1.62	**5.87**	4.61
Net earnings (loss)	**51,697**	(82,425)	57,309	**(28,423)**	565,549
Net earnings (loss) ($/basic share)	**0.33**	(0.52)	0.35	**(0.18)**	3.45
Cash flows used in investing activities	**145,828**	153,025	170,404	**480,196**	443,503
Capital expenditures [3]	**121,269**	110,610	125,639	**422,321**	447,304
Acquisitions [9]	**1,642**	5,450	5,238	**16,844**	247,294
Dispositions	**—**	—	—	**—**	182,152
Asset retirement obligations settled	**15,332**	11,745	13,582	**32,052**	28,029
Repurchase of shares	**40,106**	46,555	11,645	**123,070**	66,102
Cash dividends ($/share)	**0.12**	0.12	0.10	**0.36**	0.30
Dividends declared	**18,642**	18,981	16,367	**56,806**	49,023
% of fund flows from operations [10]	**7 %**	8 %	6 %	**6 %**	6 %
Payout [12]	**155,243**	141,336	155,588	**511,179**	524,356
% of fund flows from operations [11]	**56 %**	60 %	58 %	**54 %**	68 %
Free cash flow [4]	**153,755**	126,093	144,579	**520,764**	323,190
Long-term debt	**903,354**	915,364	966,505	**903,354**	966,505
Net debt [6]	**833,331**	906,715	1,242,522	**833,331**	1,242,522
Net debt to four quarter trailing fund flows from operations [7]	**0.6**	0.7	1.2	**0.6**	1.2
Operational					
Production [8]					
Crude oil and condensate (bbls/d)	**29,837**	32,879	31,417	**31,797**	31,407
NGLs (bbls/d)	**7,547**	7,196	7,344	**7,264**	7,261
Natural gas (mmcf/d)	**280.73**	269.39	263.80	**274.93**	265.09
Total (boe/d)	**84,173**	84,974	82,727	**84,881**	82,849
Average realized prices					
Crude oil and condensate ($/bbl)	**103.55**	108.93	106.94	**105.54**	100.64
NGLs ($/bbl)	**27.49**	31.61	27.77	**30.99**	30.89
Natural gas ($/mcf)	**6.57**	5.69	6.32	**6.13**	8.08
Production mix (% of production)					
% priced with reference to WTI	**32 %**	32 %	34 %	**32 %**	35 %
% priced with reference to Dated Brent	**13 %**	15 %	13 %	**14 %**	12 %
% priced with reference to AECO	**33 %**	33 %	34 %	**33 %**	34 %
% priced with reference to TTF and NBP	**22 %**	20 %	19 %	**21 %**	19 %
Netbacks ($/boe)					
Operating netback [12]	**41.89**	40.32	49.30	**48.23**	46.42
Fund flows from operations ($/boe) [13]	**34.78**	30.87	35.76	**39.99**	34.19
Average reference prices					
WTI (US $/bbl)	**75.10**	80.57	82.26	**77.54**	77.40
Dated Brent (US $/bbl)	**80.18**	84.94	86.76	**82.79**	82.14
AECO ($/mcf)	**0.69**	1.18	2.61	**1.45**	2.76
TTF ($/mcf)	**15.52**	13.62	14.11	**13.62**	17.39
Share information ('000s)					
Shares outstanding - basic	**155,348**	158,174	163,666	**155,348**	163,666
Shares outstanding - diluted [14]	**158,912**	161,672	167,904	**158,912**	167,904
Weighted average shares outstanding - basic	**156,624**	159,525	163,946	**159,114**	163,848
Weighted average shares outstanding - diluted [14]	**157,502**	161,069	166,392	**160,743**	167,167

(1) Fund flows from operations (FFO) is a total of segments measure comparable to net earnings (loss) that is comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, interest expense, equity based compensation settled in cash, realized gain (loss) on derivatives, realized foreign exchange gain (loss), and realized other income (expense). The measure is used to assess the contribution of each business unit to Vermilion's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations, and make capital investments. FFO does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures provided by other issuers. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(2) Fund flows from operations per share (basic and diluted) are supplementary financial measures and are not standardized financial measures under IFRS, and therefore may not be comparable to similar measures disclosed by other issuers. They are calculated using FFO (a total of segments measure) and basic/ diluted shares outstanding. The measure is used to assess the contribution per share of each business unit. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(3) Capital expenditures is a non-GAAP financial measure that is the sum of drilling and development costs and exploration and evaluation costs from the Consolidated Statements of Cash Flows. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(4) Free cash flow (FCF) and excess free cash flow (EFCF) are non-GAAP financial measures comparable to cash flows from operating activities. FCF is comprised of FFO less drilling and development and exploration and evaluation expenditures and EFCF is FCF less payments on lease obligations and asset retirement obligations settled. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(5) Free cash flow per basic share is a non-GAAP supplementary financial measure and is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. It is calculated using FCF and basic shares outstanding.

(6) Net debt is a capital management measure most directly comparable to long-term debt and is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities). More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(7) Net debt to four quarter trailing fund flows from operations is a supplementary financial measure and is not a standardized financial measure under IFRS. It may not be comparable to similar measures disclosed by other issuers and is calculated using net debt (capital management measure) and FFO (total of segment measure). The measure is used to assess the ability to repay debt. Information in this document is included by reference; refer to the "Non-GAAP and Other Specified Financial Measures" section of this document.

(8) Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.

(9) Acquisitions is a non-GAAP financial measure that is calculated as the sum of acquisitions, net of cash acquired, and acquisitions of securities from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed, and net acquired working capital. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(10) Dividends % of FFO is a supplementary financial measure that is not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers. Dividends % of FFO is calculated as dividends declared divided by FFO. The ratio is used by management as a metric to assess the cash distributed to shareholders.

(11) Payout and payout % of FFO are a non-GAAP financial measure and a non-GAAP ratio, respectively, that are not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers. Payout is comparable to dividends declared and is comprised of dividends declared plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled, while the ratio is calculated as payout divided by FFO. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(12) Operating netback is a non-GAAP financial measure comparable to net earnings and is comprised of sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(13) Fund flows from operations per boe is a supplementary financial measure that is not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers, calculated as FFO by boe production. Fund flows from operations per boe is used by management to assess the profitability of our business units and Vermilion as a whole. More information and a reconciliation to primary financial statement measures can be found in the “Non-GAAP and Other Specified Financial Measures” section of this document.

(14) Diluted shares outstanding represent the sum of shares outstanding at the period end plus outstanding awards under the Long-term Incentive Plan (“LTIP”), based on current estimates of future performance factors and forfeiture rates.

(15) Osterheide Z2-2 well (100% working interest) tested at a rate of 17.3 mmcf/d during an eight-hour flow period with flowing wellhead pressure of 4,625 psi during initial well cleanup on an adjustable choke. The completion fluid was recovered during the clean-up flow period. A final shut-in wellhead pressure of 5,757 psi and bottom hole pressure of 7,235 psi were recorded following the well test. The tested zone is the Rotliegend Wustrow formation which was encountered at 5,757m measured depth ("MD") and a 42.0 m gas column was logged with 13.8 m of net reservoir and average effective porosity of 8.3%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(16) Gojlo-1 Jug well (60% working interest) tested at rate of 5.6 mmcf/d and flowing wellhead pressure of 692 psi during a well cleanup on a 0.5938" diameter choke. The well was shut-in and then flow tested for 24 hours on 3 choke sizes (0.25", 0.3125", 0.375") to obtain necessary reservoir data and to minimize flaring. Gojlo-1Jug well tested 8.5 hours at an average rate of 2.9 mmcf/d with a flowing wellhead pressure of 861 psi on a 0.375" diameter choke. Load fluid was recovered, and no formation water was produced during the test. A final shut-in wellhead pressure of 1,009 psi and bottom hole pressure of 1,070 psi were recorded following the well test. The tested zone was the Mramor Brdo formation which was encountered at 885m MD and a 17.6m gas column was logged in

the well to the base of the reservoir with 15.6m of net reservoir and an average porosity of 31%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(17) Initial 90-day production ("IP90") for the Company's most recent five (5.0 net) wells drilled on our British Columbia lands averaged 1,000 boe/d per well. IP90 consisted of 34% tight oil, 9% NGLs, and 57% shale gas, using a conversion of six mcf of gas to one barrel of oil, based on field level estimates for the first 90 full days of production following the tie-in of the well. Production rates presented are for a limited timeframe only and may not be indicative of future performance or the ultimate recovery for a given well or pad.

Message to Shareholders

The third quarter of 2024 highlighted the strength of our diversified portfolio and the compounding impact of our share buyback program. Production during the third quarter averaged 84,173 boe/d[(1)] including the impact from a planned turnaround in Australia and the partial shut-in of some Canadian gas production due to weak AECO pricing. Our Q3 2024 production represents an increase of 2% year-over-year, or 7% on a per share basis reflecting the positive impact from our share repurchase program. We generated $275 million of fund flows from operations ("FFO") during the third quarter, representing a 16% increase over the prior quarter, primarily due to stronger European gas prices. Benchmark TTF Day Ahead pricing increased 14% over the prior quarter, averaging $15.52/mmbtu in Q3 2024, and European gas was the only commodity in our portfolio that increased quarter-over-quarter and year-over-year. European natural gas comprises 40% of our natural gas production and 22% of our total corporate production. The forward price for European natural gas benchmarks, TTF and NBP, remain strong, with 2025 forward pricing over $17/mmcf, or approximately eight times higher than AECO. This pricing dynamic supports strong cash flow and netbacks across our European business units, with 2024 operating netbacks of approximately $60/boe[(4)] from our European natural gas operations.

We invested $121 million of E&D capital during the third quarter, resulting in free cash flow ("FCF") of $154 million, of which $59 million was returned to shareholders, including $19 million in dividends and $40 million of share buybacks. Year-to-date, we have returned $180 million ($1.13/basic share) to shareholders through dividends and share buybacks, representing 38% of EFCF, including the repurchase and cancellation of 8.0 million shares, which has reduced our outstanding common shares to 155.3 million as at September 30, 2024. The balance of our free cash flow was used primarily for debt reduction, resulting in net debt decreasing by $73 million to $833 million at the end of Q3 2024 and representing a net debt to trailing FFO ratio of 0.6 times, the lowest in 15 years.

Our primary operational focus during the third quarter was on completing and testing the remaining European exploration wells drilled earlier in the year, ramping up production from the new gas plant on the SA-10 block in Croatia and ramping up production on the new battery at our Mica Montney asset in British Columbia, Canada. Subsequent to the quarter, we successfully completed drilling operations on the second deep gas exploration well in Germany and are pleased to report that we discovered gas in the reservoir and we are now proceeding with completion and testing operations. In total, we have drilled six exploration wells in Europe so far this year, all of which were successful, and we are currently in the process of drilling a third deep gas exploration well in Germany to finish out our 2024 European drilling campaign. This year was the largest exploration drilling campaign we have ever executed in Europe and the results to date help validate our geological model while providing valuable information for assessing future drilling prospects. Our team has identified numerous exploration and development prospects across our 1.7 million net acre undeveloped land base in Europe, representing well over a decade of drilling inventory with the potential to provide meaningful organic growth opportunities.

As previously disclosed, the first deep gas exploration well in Germany (100% WI) was completed in the Rotliegend zone at a depth of approximately 5,000 metres and flow tested at a restricted rate of 17 mmcf/d[(2)] of natural gas with a wellhead pressure of 4,625 psi. We also tested the third well on the SA-7 block in Croatia, at a reservoir depth of 885 metres which flow tested at 5.6 mmcf/d[(3)] of natural gas. We are very encouraged with the exploration results in Croatia, which have proven up multiple producing zones and de-risked future development and exploration targets across four discrete areas. Europe continues to be our most profitable operating region and is an area where we expect to grow organically in the years ahead as we tie in these successful wells and continue with future exploration and development drilling. Our European gas production has increased by over 40% in the last two years and we are excited about the potential for future organic growth in Germany, Croatia, and the Netherlands.

Following the start-up of the Montney battery and the Croatia SA-10 gas plant late in the second quarter, both facilities contributed to results during the third quarter. Production from both facilities increased to capacity levels by the end of the quarter, and we continue to see strong performance from these assets. This production growth was partially offset by planned maintenance at our Wandoo facility in Australia. The turnaround activity in Australia was executed as planned and production resumed late in the third quarter. Our internationally diversified asset base continues to provide strategic advantages to Vermilion by providing exposure to premium global commodity prices along with capital and operational flexibility, as evidenced by our ability to adjust the timing of the Australia turnaround to offset a delay in a third-party turnaround in Canada.

We remain on track to achieve our 2024 production and capital guidance and are in the process of finalizing our 2025 budget which will target modest production growth on a similar level of capital budget as 2024, while maintaining our return of capital payout target. We are on track to return 50% of EFCF to shareholders in 2024 through our fixed dividend and variable share buybacks, representing approximately 10% of our market capitalization, and expect to continue providing ratable dividend increases and repurchasing shares in future periods. We believe Vermilion is well positioned to execute on this plan given our robust asset base and strong balance sheet, which is at the lowest leverage in well over a decade. We plan to release our 2025 budget later in the year and look forward to providing further details on our capital investment and shareholder return plans for 2025.

Q3 2024 Operations Review

North America

Production from our North American operations averaged 53,936 boe/d[(1)] in Q3 2024, a decrease of 2% from the previous quarter due to declines in our Deep Basin and United States assets and some Canadian gas production shut-in due to weak AECO pricing, partially offset by new production from our recent BC Mica Montney wells.

At Mica, we completed and brought on production five (5.0 net) BC Montney liquids-rich shale gas wells. In the Deep Basin, we drilled three (2.3 net), completed three (2.3 net), and brought on production one (1.0 net) Mannville liquids-rich conventional natural gas wells. In Saskatchewan, we drilled, completed, and brought on production five (5.0 net) light and medium crude oil wells, while in the United States, five (0.2 net) non-operated light and medium crude oil wells were brought on production.

In Canada, the five (5.0 net) Montney wells from the 9-21 pad that were brought on production during the third quarter have produced at an average IP90 rate of over 1,000 boe/d[(5)] per well (43% liquids)[(5)], which is in line with expectations. These 9-21 wells were flowed preferentially through our new 8-33 BC Montney battery to maximize liquids recovery during a period of low natural gas prices. The gas stream from our BC Montney wells was also partially restricted due to capacity constraints on the sales gas line from the 8-33 BC Montney battery. We plan to increase takeaway capacity by de-bottlenecking as part of our infrastructure expansion scheduled for 2025. The total drill, complete, equip and tie-in ("DCET") cost for the 9-21 pad was approximately $9.6 million per well as we continue to make progress towards our normalized targeted cost range of $9.0 to $9.5 million per well. The new battery and water infrastructure have achieved 99% run time since starting up and are contributing to these cost savings.

International

Production from our International operations averaged 30,237 boe/d[(1)] in Q3 2024, an increase of 1% from the previous quarter primarily due to new production from our SA-10 block in Croatia and higher runtime in Germany and Ireland, partially offset by planned maintenance downtime in Australia.

In Germany, we successfully completed testing operations for our first deep gas exploration well drilled earlier this year. The well flow tested at a restricted rate of 17 mmcf/d[(2)] of natural gas with a wellhead pressure of 4,625 psi, which supports our expectation that deliverability would have been higher without testing equipment limitations. Tie-in operations are progressing to bring the well on production in the first half of 2025. We commenced drilling on our second deep gas exploration well (0.3 net) in August 2024 and successfully completed drilling operations at the end of October 2024. We are pleased to report that we discovered gas within the reservoir and are now proceeding with completion and testing operations. Subsequent to the quarter, we commenced drilling on our third deep gas exploration well (1.0 net) in October 2024. We anticipate results from the second well test and third well drilling operations in the first half of 2025.

In Croatia, we successfully increased production on the SA-10 block after commissioning the gas plant in late June 2024. Production in Q3 2024 averaged 1,855 boe/d (100% European natural gas) and currently exceeds 2,000 boe/d. On the SA-7 block, we completed testing on the third well of our four-well program, which flow tested at 5.6 mmcf/d[(3)] of natural gas.

During Q3 2024 we achieved a major safety milestone in Ireland, where we celebrated two years and one million man-hours without a lost time incident. We have successfully completed many complex projects over the past two years, including the refrigeration project and major turnarounds, while upholding our high standard for safety. The Corrib facility has maintained steady-state operations with an exceptional plant uptime record, and continues to be a major contributor to our operational and financial success.

In Australia, planned maintenance at our Wandoo facility was executed during Q3 2024. Production resumed late in the quarter and continues to perform well.

Outlook and Guidance Update

We have tightened our 2024 production guidance range to 84,000 to 85,000 boe/d to reflect increased certainty on annual production levels. Our Q4 2024 production will be impacted by planned third-party turnaround activity in Alberta and partial shut-in of some Canadian gas production in response to weak AECO prices, totaling approximately 2,000 boe/d combined. Our 2024 capital budget of $600 to $625 million remains unchanged, with Q4 2024 representing an active capital program in the Deep Basin, Saskatchewan, and the Montney in Canada, along with participating in several non-operated wells in the United States and continuing with drilling operations on the two deep gas exploration wells in Germany.

Commodity Hedging

Vermilion hedges to manage commodity price exposures and increase the stability of our cash flows. In aggregate, as of November 6, 2024, we have 38% of our expected net-of-royalty production hedged for the remainder of 2024. With respect to individual commodity products, we have hedged 53% of our European natural gas production, 41% of our crude oil production, and 23% of our North American natural gas volumes, respectively. Please refer to the Hedging section of our website under Invest With Us for further details using the following link: https://www.vermilionenergy.com/invest-with-us/hedging.

Board of Directors

Mr. Robert Michaleski has stepped down as Chair of the Board of the Directors of the Company effective November 1, 2024 and has advised of his intention to retire from Vermilion's Board of Directors, effective at the Company's next Annual General Meeting, currently scheduled for May 7, 2025. Mr. Michaleski joined Vermilion's Board of Directors in 2016 as an Independent Director and assumed the role of Chair of the Board on September 1, 2022. We want to thank Mr. Michaleski for his efforts and invaluable contributions to the Company, including providing leadership and guidance during his tenure as Chair and serving on the Audit Committee and Governance and Human Resources Committee.

As part of our planned board succession, Vermilion is pleased to announce that Mr. Myron Stadnyk has been chosen and has assumed the role of Chair of the Board effective November 1, 2024. Mr. Stadnyk was appointed to Vermilion's Board of Directors in 2022 and has been a valuable contributor to the Company as a member of the Health, Safety and Environment Committee and Technical Committee. He has also provided insightful guidance and vision in helping to shape Vermilion's strategy, along with sharing his in-depth technical knowledge as Vermilion advanced several new growth projects. Mr. Stadnyk has over 39 years of business and industry knowledge, with extensive experience in executive leadership, operational excellence, governance, health, safety, and environment. He most recently served as the President and Chief Executive Officer of ARC Resources Ltd. where he led ARC's transformation to a top-tier Montney producer, demonstrating outstanding strategic leadership. For Mr. Stadnyk's full biography as well as further information on the Board, please visit https:// www.vermilionenergy.com/about-us/our-directors/.

(Signed "Dion Hatcher")

Dion Hatcher
President & Chief Executive Officer
November 6, 2024

(1) Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.

(2) Osterheide Z2-2 well (100% working interest) tested at a rate of 17.3 mmcf/d during an eight-hour flow period with flowing wellhead pressure of 4,625 psi during initial well cleanup on an adjustable choke. The completion fluid was recovered during the clean-up flow period. A final shut-in wellhead pressure of 5,757 psi and bottom hole pressure of 7,235 psi were recorded following the well test. The tested zone is the Rotliegend Wustrow formation which was encountered at 5,757m measured depth ("MD") and a 42.0 m gas column was logged with 13.8 m of net reservoir and average effective porosity of 8.3%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(3) Gojlo-1 Jug well (60% working interest) tested at rate of 5.6 mmcf/d and flowing wellhead pressure of 692 psi during a well cleanup on a 0.5938" diameter choke. The well was shut-in and then flow tested for 24 hours on 3 choke sizes (0.25", 0.3125", 0.375") to obtain necessary reservoir data and to minimize flaring. Gojlo-1Jug well tested 8.5 hours at an average rate of 2.9 mmcf/d with a flowing wellhead pressure of 861 psi on a 0.375" diameter choke. Load fluid was recovered, and no formation water was produced during the test. A final shut-in wellhead pressure of 1,009 psi and bottom hole pressure of 1,070 psi were recorded following the well test. The tested zone was the Mramor Brdo formation which was encountered at 885m MD and a 17.6m gas column was logged in the well to the base of the reservoir with 15.6m of net reservoir and an average porosity of 31%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(4) 2024 operating netback based on Company estimates using November 1, 2024, strip pricing: Brent US$80.72/bbl; WTI US$75.79/bbl; LSB = WTI less US$5.97/bbl; TTF $14.61/mmbtu; NBP $14.15/mmbtu; AECO $1.43/mcf; CAD/USD 1.37; CAD/EUR 1.49 and CAD/AUD 0.91. Operating netback is a non-GAAP financial measure most directly comparable to net earnings and is comprised of sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. Operating netback per boe is not a standardized financial measure under IFRS and, therefore may not be comparable with the calculation of similar financial measures disclosed by other entities.

(5) Initial 90-day production ("IP90") for the Company's most recent five (5.0 net) wells drilled on our British Columbia lands averaged 1,000 boe/d per well. IP90 consisted of 34% tight oil, 9% NGLs, and 57% shale gas, using a conversion of six mcf of gas to one barrel of oil, based on field level estimates for the first 90 full days of production following the tie-in of the well. Production rates presented are for a limited timeframe only and may not be indicative of future performance or the ultimate recovery for a given well or pad.

Non-GAAP and Other Specified Financial Measures

This report and other materials released by Vermilion includes financial measures that are not standardized, specified, defined, or determined under IFRS and are therefore considered non-GAAP or other specified financial measures and may not be comparable to similar measures presented by other issuers. These financial measures include:

Total of Segments Measures

Fund flows from operations (FFO): Most directly comparable to net earnings (loss), FFO is a total of segments measure comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, interest expense, equity based compensation settled in cash, realized gain (loss) on derivatives, realized foreign exchange gain (loss), and realized other income (expense). The measure is used to assess the contribution of each business unit to Vermilion's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. Reconciliation to the primary financial statement measures can be found below.

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**490,095**	**61.97**	475,532	62.92	**1,477,055**	**62.63**	1,499,586	66.57
Royalties	**(42,738)**	**(5.40)**	(32,209)	(4.26)	**(137,901)**	**(5.85)**	(146,546)	(6.51)
Transportation	**(26,693)**	**(3.38)**	(21,460)	(2.84)	**(74,972)**	**(3.18)**	(66,415)	(2.95)
Operating	**(138,806)**	**(17.55)**	(122,870)	(16.26)	**(428,347)**	**(18.16)**	(396,444)	(17.60)
General and administration	**(21,803)**	**(2.76)**	(20,959)	(2.77)	**(72,043)**	**(3.05)**	(60,906)	(2.70)
Corporate income tax expense	**(12,707)**	**(1.61)**	(31,368)	(4.15)	**(50,445)**	**(2.14)**	(72,558)	(3.22)
Windfall taxes	**—**	**—**	(21,953)	(2.90)	**—**	**—**	(78,177)	(3.47)
PRRT	**(507)**	**(0.06)**	—	—	**(14,928)**	**(0.63)**	—	—
Interest expense	**(21,187)**	**(2.68)**	(20,218)	(2.68)	**(60,641)**	**(2.57)**	(62,303)	(2.77)
Equity based compensation	**—**	**—**	—	—	**(14,361)**	**(0.61)**	—	—
Realized gain on derivatives	**49,891**	**6.31**	73,625	9.74	**316,523**	**13.42**	155,628	6.91
Realized foreign exchange gain	**1,155**	**0.15**	2,089	0.28	**5,293**	**0.22**	997	0.04
Realized other income	**(1,676)**	**(0.21)**	(9,991)	(1.32)	**(2,148)**	**(0.09)**	(2,368)	(0.11)
Fund flows from operations	**275,024**	**34.78**	270,218	35.76	**943,085**	**39.99**	770,494	34.19
Equity based compensation	**(6,412)**		(6,362)		**(8,070)**		(34,885)	
Unrealized (loss) gain on derivative instruments [(1)]	**(1,052)**		(65,294)		**(315,585)**		38,581	
Unrealized foreign exchange gain (loss) [(1)]	**(11,382)**		(12,042)		**(29,954)**		7,604	
Accretion	**(19,126)**		(20,068)		**(55,269)**		(58,718)	
Depletion and depreciation	**(180,164)**		(151,087)		**(519,782)**		(453,607)	
Deferred tax (expense) recovery	**(4,713)**		42,489		**(42,025)**		79,435	
Gain on business combination	**—**		—		**—**		445,094	
Loss on disposition	**—**		—		**—**		(226,828)	
Unrealized other expense	**(478)**		(545)		**(823)**		(1,621)	
Net earnings (loss)	**51,697**		57,309		**(28,423)**		565,549	

(1) Unrealized (loss) gain on derivative instruments, Unrealized foreign exchange (loss) gain, and Unrealized other expense are line items from the respective Consolidated Statements of Cash Flows.

Non-GAAP Financial Measures and Non-GAAP Ratios

Free cash flow (FCF) and excess free cash flow (EFCF): Most directly comparable to cash flows from operating activities, FCF is a non-GAAP measure calculated as fund flows from operations less drilling and development costs and exploration and evaluation costs and EFCF is comprised of FCF less payments on lease obligations and asset retirement obligations settled. FCF is used by management to determine the funding available for investing and financing activities including payment of dividends, repayment of long-term debt, reallocation into existing business units and deployment into new ventures. EFCF is used by management to determine the funding available to return to shareholders after costs attributable to normal business operations. Reconciliation to the primary financial statement measures can be found in the following table.

($M)	Q3 2024	Q3 2023	2024	2023
Cash flows from operating activities	**134,547**	118,436	**755,164**	680,697
Changes in non-cash operating working capital	**125,145**	138,200	**155,869**	61,768
Asset retirement obligations settled	**15,332**	13,582	**32,052**	28,029
Fund flows from operations	**275,024**	270,218	**943,085**	770,494
Drilling and development	**(118,809)**	(119,404)	**(410,457)**	(436,802)
Exploration and evaluation	**(2,460)**	(6,235)	**(11,864)**	(10,502)
Free cash flow	**153,755**	144,579	**520,764**	323,190
Payments on lease obligations	**(7,547)**	(4,053)	**(19,479)**	(13,117)
Asset retirement obligations settled	**(15,332)**	(13,582)	**(32,052)**	(28,029)
Excess free cash flow	**130,876**	126,944	**469,233**	282,044

Capital expenditures: Most directly comparable to cash flows used in investing activities, capital expenditures is a non-GAAP measure calculated as the sum of drilling and development costs and exploration and evaluation costs as derived from the Consolidated Statements of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital. Reconciliation to the primary financial statement measures can be found below.

($M)	Q3 2024	Q3 2023	2024	2023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Capital expenditures	**121,269**	125,639	**422,321**	447,304

Payout and payout % of FFO: Payout and payout % of FFO are, respectively, a non-GAAP financial measure and non-GAAP ratio, most directly comparable to dividends declared. Payout is comprised of dividends declared plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled, and payout % of FFO is calculated as payout divided by FFO (total of segments measure). The measure is used by management to assess the amount of cash distributed back to shareholders and reinvested in the business for maintaining production and organic growth. Payout as a percentage of FFO is also referred to as the payout ratio or sustainability ratio).The reconciliation of the measure to the primary financial statement measure can be found below.

($M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Dividends declared	**18,642**	16,367	**56,806**	49,023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Asset retirement obligations settled	**15,332**	13,582	**32,052**	28,029
Payout	**155,243**	155,588	**511,179**	524,356
% of fund flows from operations	**56 %**	58 %	**54 %**	68 %

Return on capital employed (ROCE): A non-GAAP ratio, ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process; the comparable primary financial statement measure is earnings before income taxes. ROCE is calculated by dividing net earnings (loss) before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the balance sheets at the beginning and end of the twelve-month period.

	Twelve Months Ended	
($M)	Sep 30, 2024	Sep 30, 2023
Net (loss) earnings	**(831,559)**	960,957
Taxes	**(4,597)**	537,895
Interest expense	**83,550**	84,809
EBIT	**(752,606)**	1,583,661
Average capital employed	**5,995,108**	6,024,614
Return on capital employed	**(13)%**	26 %

Adjusted working capital: Defined as current assets less current liabilities, excluding current derivatives and current lease liabilities. The measure is used by management to calculate net debt, a capital management measure disclosed below.

($M)	As at Sep 30, 2024	Dec 31, 2023
Current assets	**651,197**	823,514
Current derivative asset	**(92,537)**	(313,792)
Current liabilities	**(521,669)**	(696,074)
Current lease liability	**23,545**	21,068
Current derivative liability	**9,487**	732
Adjusted working capital	**70,023**	(164,552)

Acquisitions: The sum of acquisitions, net of cash acquired and acquisitions of securities from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed, and net acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity and is most directly comparable to cash flows used in investing activities. A reconciliation to the acquisitions line items in the Consolidated Statements of Cash Flows can be found below.

($M)	Q3 2024	Q3 2023	Q3 2024	Q3 2023
Acquisitions, net of cash acquired	**1,642**	3,191	**7,471**	139,612
Acquisition of securities	**—**	2,047	**9,373**	4,155
Acquired working capital	**—**	—	**—**	103,527
Acquisitions	**1,642**	5,238	**16,844**	247,294

Capital Management Measure

Net debt: Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements" that is most directly comparable to long-term debt. Net debt is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities), and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations.

($M)	As at Sep 30, 2024	Dec 31, 2023
Long-term debt	**903,354**	914,015
Adjusted working capital	**(70,023)**	164,552
Net debt	**833,331**	1,078,567
Ratio of net debt to four quarter trailing fund flows from operations	**0.6**	0.9

Supplementary Financial Measures

Diluted shares outstanding: The sum of shares outstanding at the period end plus outstanding awards under the Long-term Incentive Plan ("LTIP"), based on current estimates of future performance factors and forfeiture rates.

('000s of shares)	Q3 2024	Q3 2023
Shares outstanding	**155,348**	163,666
Potential shares issuable pursuant to the LTIP	**3,564**	4,238
Diluted shares outstanding	**158,912**	167,904

Fund flows from operations per basic and diluted share: Management assesses fund flows from operations on a per share basis as we believe this provides a measure of our operating performance after taking into account the issuance and potential future issuance of Vermilion common shares. Fund flows from operations per basic share is calculated by dividing fund flows from operations (total of segments measure) by the basic weighted average shares outstanding as defined under IFRS. Fund flows from operations per diluted share is calculated by dividing fund flows from operations by the sum of basic weighted average shares outstanding and incremental shares issuable under the equity based compensation plans as determined using the treasury stock method.

Operating netback: Most directly comparable to net earnings (loss), operating netback is calculated as sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations.

Fund flows from operations per boe: Management uses fund flows from operations per boe to assess the profitability of our business units and Vermilion as a whole. Fund flows from operations per boe is calculated by dividing fund flows from operations (total of segments measure) by boe production.

Net debt to four quarter trailing fund flows from operations: Management uses net debt to four quarter trailing fund flows from operations to assess the Company's ability to repay debt. Net debt to four quarter trailing fund flows from operations is calculated as net debt (capital management measure) divided by fund flows from operations (total of segments measure) from the preceding four quarters.

Management's Discussion and Analysis and Consolidated Financial Statements

To view Vermilion's Management's Discussion and Analysis and Interim Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2024 and 2023, please refer to SEDAR+ (www.sedarplus.ca) or Vermilion's website at www.vermilionenergy.com.

About Vermilion

Vermilion is an international energy producer that seeks to create value through the acquisition, exploration, development and optimization of producing assets in North America, Europe and Australia. Our business model emphasizes free cash flow generation and returning capital to investors when economically warranted, augmented by value-adding acquisitions. Vermilion's operations are focused on the exploitation of light oil and liquids-rich natural gas conventional and unconventional resource plays in North America and the exploration and development of conventional natural gas and oil opportunities in Europe and Australia.

Vermilion's priorities are health and safety, the environment, and profitability, in that order. Nothing is more important to us than the safety of the public and those who work with us, and the protection of our natural surroundings. We have been recognized by leading ESG rating agencies for our transparency on and management of key environmental, social and governance issues. In addition, we emphasize strategic community investment in each of our operating areas.

Vermilion trades on the Toronto Stock Exchange and the New York Stock Exchange under the symbol VET.

Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward-looking statements or information under applicable securities legislation. Such forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements or information in this document may include, but are not limited to: capital expenditures, including Vermilion's 2024 guidance, and Vermilion's ability to fund such expenditures; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; wells expected to be drilled and the timing thereof; exploration and development plans and the timing thereof; future drilling prospects; the ability of our asset base to deliver modest production growth; the evaluation of international acquisition opportunities; statements regarding the return of capital; our asset petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2024 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange and inflation rates; the payment and amount of future dividends; the effect of possible changes in critical accounting estimates; the Company's review of the impact of potential changes to financial reporting standards; the potential financial impact of climate-related risks; Vermilion's goals regarding its debt levels, including maintenance of a ratio of net debt to four quarter trailing funds flow from operations; statements regarding Vermilion's hedging program and the stability of our cash flows; operating and other expenses; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability; the timing of regulatory proceedings and approvals; and the release of our 2025 budget and the timing thereof.

Such forward-looking statements or information are based on a number of assumptions, all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things: the ability of Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion to market crude oil, natural gas liquids, and natural gas successfully to current and new customers; the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation; the timely receipt of required regulatory approvals; the ability of Vermilion to obtain financing on acceptable terms; foreign currency exchange rates and interest rates; future crude oil, natural gas liquids, and natural gas prices; management's expectations relating to the timing and results of exploration and development activities; the impact of Vermilion's dividend policy on its future cash flows; credit ratings; hedging program; expected earnings/(loss) and adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and free cash flow and expected future cash flow and free cash flow per share; estimated future dividends; financial strength and flexibility; debt and equity market conditions; general economic and competitive conditions; ability of management to execute key priorities; and the effectiveness of various actions resulting from the Vermilion's strategic priorities.

Although Vermilion believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Vermilion can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding Vermilion's financial position and business objectives, and the information may not be appropriate for other purposes. Forward-looking statements or information are based on current expectations, estimates, and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Vermilion and described in the forward-looking statements or information. These risks and uncertainties include, but are not limited to: the ability of management to execute its business plan; the risks of the oil and gas industry, both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil, natural gas liquids, and natural gas; risks and uncertainties involving geology of crude oil, natural gas liquids, and natural gas deposits; risks inherent in Vermilion's marketing operations, including credit risk; the uncertainty of reserves estimates and reserves life and estimates of resources and associated expenditures; the uncertainty of estimates and projections relating to production and associated expenditures; potential delays or changes in plans with respect to exploration or development projects; Vermilion's ability to enter into or renew leases on acceptable terms; fluctuations in crude oil, natural gas liquids, and natural gas prices, foreign currency exchange rates, interest rates and inflation; health, safety, and environmental risks; uncertainties as to the availability and cost of financing; the ability of Vermilion to add production and reserves through exploration and development activities; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; uncertainty in amounts and timing of royalty payments; risks associated with existing and potential future law suits and regulatory actions against or involving Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

This document contains references to sustainability/ESG data and performance that reflect metrics and concepts that are commonly used in such frameworks as the Global Reporting Initiative, the Task Force on Climate-related Financial Disclosures, and the Sustainability Accounting Standards Board. Vermilion has used best efforts to align with the most commonly accepted methodologies for ESG reporting, including with respect to climate data and information on potential future risks and opportunities, in order to provide a fuller context for our current and future operations. However, these methodologies are not yet standardized, are frequently based on calculation factors that change over time, and continue to evolve rapidly. Readers are particularly cautioned to evaluate the underlying definitions and measures used by other companies, as these may not be comparable to Vermilion’s. While Vermilion will continue to monitor and adapt its reporting accordingly, the Company is not under any duty to update or revise the related sustainability/ESG data or statements except as required by applicable securities laws.
The forward-looking statements or information contained in this document are made as of the date hereof and Vermilion undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events, or otherwise, unless required by applicable securities laws.

This document discloses certain oil and gas metrics, including DCET costs, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this MD&A to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the Company's performance in previous periods and therefore such metrics should not be unduly relied upon. DCET costs includes all capital spent to drill, complete, equip and tie-in a well. Additional oil and gas metrics in this document may include, but are not limited to:

Boe Equivalency: Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Estimates of Drilling Locations: Unbooked drilling locations are the internal estimates of Vermilion based on Vermilion's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by Vermilion's management as an estimation of Vermilion's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Vermilion will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which Vermilion will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been de-risked by Vermilion drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management of Vermilion has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Initial Production Rates and Short-Term Test Rates: This document discloses test rates of production for certain wells over short periods of time (i.e. 24 hours, IP30, IP60, IP90, etc.), which are preliminary and not determinative of the rates at which those or any other wells will commence production and thereafter decline. Short-term test rates are not necessarily indicative of long-term well or reservoir performance or of ultimate recovery. Although such rates are useful in confirming the presence of hydrocarbons, they are preliminary in nature, are subject to a high degree of predictive uncertainty as a result of limited data availability and may not be representative of stabilized on-stream production rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Production over a longer period will also experience natural decline rates, which can be high in certain plays in which the Company operates, and may not be consistent over the longer term with the decline experienced over an initial production period. Initial production or test rates may also include recovered "load" fluids used in well completion stimulation operations. Actual results will differ from those realized during an initial production period or short-term test period, and the difference may be material.

Financial data contained within this document are reported in Canadian dollars, unless otherwise stated.